Upgrading and Enhancing the Generator Protection System by Making Use of Digital Systems

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ABSTRACT

Upgrading of power plant systems and equipment is becoming a major theme for many utilities. Due to operational cost pressures, competitiveness, life extension, and the desire for better productivity, condition assessment programs are being implemented. One aspect of this is the enhancement/upgrade of existing generator protection schemes with digital systems. Traditionally this protection has been provided by a complement of discrete component relays. These relays have included both electromechanical and static types. Considering a digital enhancement/upgrade offers the owner of installed generation equipment several unique advantages. These include more complete machine protection, diagnostics capabilities for greater productivity and maintenance optimization, life extension with minimal implementation, and the operational advantages of sequence of events, present values and communications capabilities.

I. INTRODUCTION

In recent years, due to the electricity market competitiveness, many utilities have completely stopped all new plant construction even though the electrical power demand continues to increase at a constant rate in all states and service territories. Many utilities have reviewed their generating reserve capacity and generation reliability, and have implemented plans to optimize their investment, reduce capital and operating budget. The generation reserve capacity must be reduced to a minimum yet the reliability of service to its customers must be maintained and at the same time the utility must continue to provide that service as cost effective as possible. The function of the unit generators in the power system may be changing under this new operating condition and requirement.

At Florida Power and Light (FPL), the power plant system condition assessment is being considered mainly in the area of plant/unit protection and control. The condition assessment provides a systematic approach for determining the present state of the facility, so that modification can be determined to ensure the quality of both the unit performance and the unit interconnection at the substation. The unit performance depends on the reliability of the plant protection and control systems. This will in turn help meet the new system design criteria.

Furthermore, this condition assessment is more critical to the nuclear units due to their aging and their critical service as base-load units. This paper only addresses the unit condition assessment which identifies those changes necessary for meeting the new operating objectives and mainly how the use of current digital generator protection systems helps to meet these objectives.

II. UTILITY POWER PLANT CONDITION ASSESSMENT

First and foremost the power system's requirements of the defined power plant unit need to be determined. Specifically, the remaining operating life and type of operation required (base loaded, cycling, etc.) need to be identified. Once this macro requirement is defined, the specific details and action plans for individual equipment and systems can be developed.

This will establish the actions necessary to meet the required goals and remaining life targets.

Objective

The objective of this condition assessment program is to identify, on a site-by-site basis, changes and enhancement opportunities which can be implemented at minimal cost and meet the specific plant's performance requirements. The condition assessment includes the following:

1. A systematic review of the plant's existing protection and control, and metering application.

   This would identify the necessary changes to these devices, to insure that the plant design meets the new operating objective.

2. Identification of systems, protection and control equipment that are obsolete or do not meet the new design and operating conditions.

   Because the importance of the unit may have changed, it may be necessary to provide a more complete unit protection for dependability and security. Furthermore, the equipment maintenance cycle is extended to minimize operating cost. To accomplish this the equipment must include self-diagnostics for maintenance optimization. Additionally, in order to optimize space utilization, the unit protection and control system must include an on-line monitoring, a sequence of events recorder and oscillography capability for analysis by remote communication.

3. Processing recommendations for replacement of the equipment and the capital operating budget.

4. Feedback to FPL's System Reliability Centered Maintenance (RCM) Program.

   The RCM program determines the *equipment maintenance requirements* in a system. These requirements are based on the consequences of a system failure that could result from the equipment failing. The process quantifies the importance of each component and determines the equipment's critical functionality in the system. This process is motivated primarily by equipment failure consequences rather than by equipment preservation.

Again, the objective of this On-Site Assessment Program is to identify, on a site-by-site basis, enhancements/upgrades which will enable specific plants to meet their performance requirements based on the above mentioned issues. Enhancements/upgrades which will enable specific plants to meet their performance requirements are identified in the assessment. One area of this program is the consideration of use of current digital generator protection systems.

III. DIGITAL GENERATOR PROTECTION IMPLEMENTATION

The upgrading of existing generator protection schemes with Digital Generator Protection equipment offer the owner of installed generation equipment several unique advantages. These include more complete machine protection, diagnostics capabilities for greater productivity and maintenance optimization, life extension with minimal implementation, and the operational advantages of sequence of events, present values and communications capabilities.

With these additional capabilities avoidance and/or reduction of forced outage time more than justify the retrofit costs. In older installations the electromechanical relays that have been in service for many years are approaching their end of life due to insulation deterioration. Replacement of these relays with new electromechanical or analog relays would not be as cost effective as implementing a digital system. An example illustrating the estimated reduction in costs of outages compared to the retrofit costs are discussed later in the paper.

The following areas are examined to illustrate the benefits realized by retrofitting existing generator protection schemes with the digital generator protection systems. GE's Digital Generator Protection System (DGP) is used as an example to illustrate the benefits in the discussions that follow.

A. MORE COMPLETE MACHINE PROTECTION.

B. SELF-DIAGNOSTICS AND TESTING FOR MAINTENANCE OPTIMIZATION.

C. SEQUENCE OF EVENTS, OSCILLOGRAPHY, PRESENT VALUES, AND COMMUNICATIONS.

D. COST SAVINGS BASED ON IMPROVED PRODUCTIVITY AND REDUCED UNIT OUTAGES.

E. ADDITIONAL CONSIDERATIONS

The main objective is to improve the protection, provide better maintenance of the protection system through self tests, and predictive maintenance. Each of these aspects bring an important benefit to the user which will be discussed individually.

A. MORE COMPLETE MACHINE PROTECTION.

More and more demands are being placed on the older existing units. Many of these units are not fully protected with respect to present practice. When these units were initially put into service years ago the technology of the time did not offer the protective functions that are available today.

The following protective functions are included in a typical digital generator protection system:

1. Stator Differential (87G)
2. Current Unbalance (46)
3. Loss of Excitation (40)
4. Reverse Power (32)
5. Time Overcurrent with Voltage Restraint (51V)
6. 100 % Stator Ground (64G/27TN)
7. Over-excitation (24)
8. Overvoltage (59)
9. Over and Under frequency (81)
10. Voltage Transformer Fuse Failure (VTFF)
11. Accidental Energizing

Many existing units are not fully equipped with all these protective functions and in many instances the original protective functions are not sufficiently sensitive or stable. Protective functions such as 100% Stator Ground Fault, Over-Excitation, and Accidental Energizing would be good additions to complement the existing generator protection scheme. Recent incidents which have occurred in the industry that have caused damage and forced outages could have been prevented or mitigated if this protection had been installed. Improved protection will help in extending the life of these older generators by minimizing fault clearing times and the duration of exposure to abnormal operating conditions. Damage due to the incidents such as accidental energizing, which are potentially devastating, can be eliminated with proper application of this protection feature. Table 1 illustrates some of the differences between the digital systems and older units protection schemes using electromechanical relays.

Table 1 Examples of Enhanced Protection by the Digital Versus Typical Electromechanical Systems

DIGITAL SYSTEM	ELECTROMECHANICAL PROTECTION	COMMENTS
100% Stator Protection	IAV	IAV protects 90-95%. Choice of 27TN & 64G in digital system for 100% Stator Ground protection.
Complete Overexcitation Protection	Two Set Point Overexcitation Protection If any	Digital system better coordinates with Transformer and Generator Capability curves.
Accidental Energizing of Turbine Generator	Not Supplied (Note 1)	Accelerating from Turning Gear not protected against in Older Units.
Four Step Under frequency	Not Generally Supplied (Note 2)	
Unbalanced Armature Currents Protection	INC77	More Sensitive Protection for Negative Sequence Current Conditions.
Loss of Excitation Two Zones	Generally One Zone of Protection	Possibility of False Trip with One Zone Protection During Power Swings.
Reverse Power Protection	Lack of sensitivity for some applications	Digital system offers better sensitivity.
Voltage Transformer Fuse Failure	Voltage Balance Relay Requires Two Voltage Transformers	Detection By Analysis Requires Only One Voltage Transformer.
Frequency Tracking Algorithm	Poor Frequency Response (see Figures 1a and 1b)	Digital Systems Provide Superior Protection At Off Frequency Operation. (e.g. During Startup)

Note 1. Either not supplied or has a complicated scheme associated with it.
Note 2. If supplied has unreliable performance which requires complex scheme to provide security.

Frequency Vs Sensitivity - EM Relays

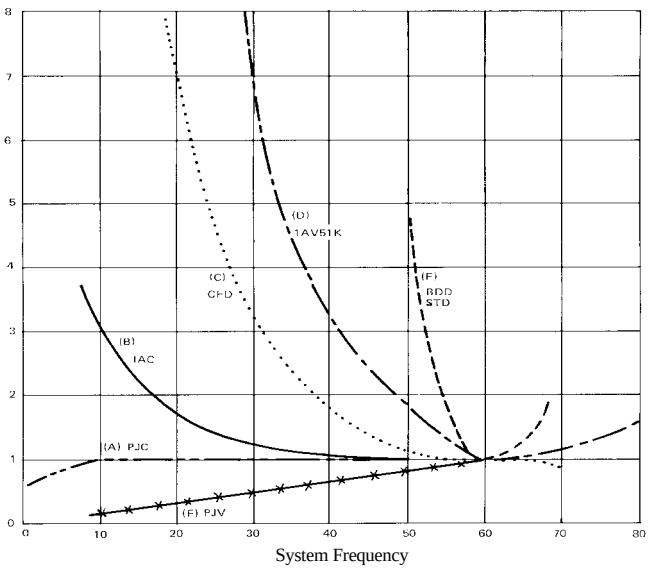

Figure 1a

Frequency Vs Sensitivity - DGP Relay System

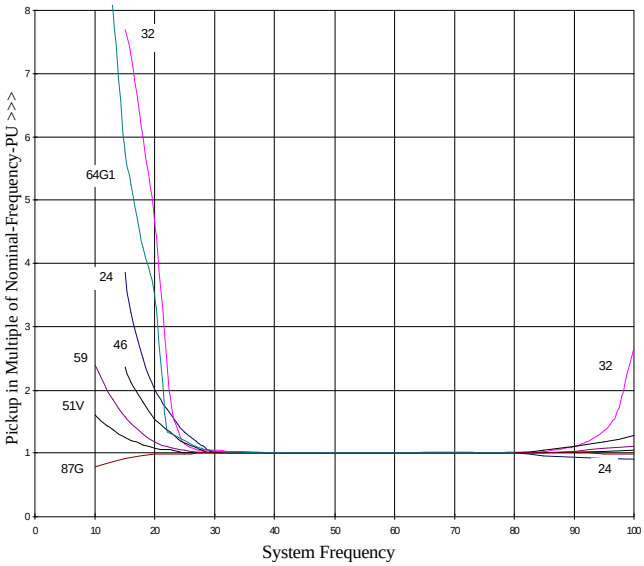

Figure 1b

B. SELF-DIAGNOSTICS AND TESTING FOR MAINTENANCE OPTIMIZATION.

The following features support the concept of life extension and maintenance optimization. The ability of the system to continuously check itself allows the user the flexibility to reduce maintenance outage and test time. The user is immediately alerted to any problem and the diagnostics identify the specific nature of the problem to eliminate costly troubleshooting delays.

Start-Up Self Tests

Generally the most comprehensive testing of the digital system is performed during a power-up. Since the digital system is not performing any protection activities at that time, tests (such as RAM tests) that could be disruptive to run-time processing are performed during the start-up. All the processors participate in the start-up self testing. The processors communicate their results to each other so that any failures found can be reported to the user, and so that each processor successfully completes its assigned self-tests before the digital system begins protection activity.

If a critical self-test failure is detected, the digital system will not continue its start-up, nor will it cause a reset. The digital system status will be stored, and a diagnostic message will be printed. The critical alarm output will be issued .

Run-Time Self Tests

Each of the processors will have "idle time" when the system is in a quiescent state; i.e., when the digital system is not performing fault or post-fault processing. During this idle time, each processor will perform "background" self-tests that are not disruptive to the foreground processing; that is, tests that do not inhibit interrupts to any processor.

Benefits to the User:

1. Very comprehensive testing before going on line.
2. Continuous testing during normal operation without interfering with any functional performance.
3. Alarms both critical and non critical problems.
4. Identifies bad board / components in diagnostics.
5. Over 80 different diagnostic messages.
6. Reduce the frequency of maintenance

Trip Circuit Monitor

The trip circuit monitor consists of DC voltage and current monitors. Under normal condition, DC voltage across the trip contacts is continuously monitored. If the DC voltage becomes virtually zero, then the trip circuit has "failed open". A non-critical alarm is generated when the self test feature detects this condition.

When the digital system issues a trip, DC current through each of the appropriate trip contacts is monitored. The trip relay is sealed-in, as long as the current is flowing, to protect the contact. A minimum current of 150 milliamperes is required for this circuit to recognize the trip current. Status of the trip current flow, following issuance of any trip, is logged in the sequence of events.

Benefits to the User:

1. Recognizes and alerts of an open trip circuit.
2. Checks the trip circuit integrity when breaker and lockout relay are tripped.

C. SEQUENCE OF EVENTS, OSCILLOGRAPHY, PRESENT VALUES, AND COMMUNICATIONS.

Sequence of Events

This function time-tags and stores in memory the last 100 events. The resolution of the time-tagging is 1 millisecond. The event list contains power system events, operator actions, and self-test alarms. The digital system includes a real time clock that can run freely or be synchronized from an external signal such as from a satellite. This is a useful feature when performing a fault or incident analysis and could conceivably reduce outage time and allows faster service restoration with higher confidence.

Fault Report and Oscillographic Data

A fault report includes unit ID, date and time, system operating time, pre-fault metering values, fault currents and voltages, trip/fault types, and up to 14 sequence of events points logged after the fault report was initiated. Figure 2 shows an example of a fault report.

```
MPS                                                              0000

                              FAULT REPORT

Station ID:  XYZ Power Station
Generator ID:  GENERATOR No. 1

                              FAULT#: 02
        FAULT DATE: 08/09/93                  FAULT TIME: 05:10:37.829
        FAULT TYPE: ABC
        TRIP TYPE: 87G                        SYSTEM OPERATING TIME: 000014

        PREFAULT                              FAULT
        ----------                            ------------------------------------------
        IAS: 0128.0  A                        IAS: 014672 A    IAR: 015664 A
        IBS: 0208.0  A                        IBS: 015264 A    IBR: 016704 A
        ICS: 0080.0  A                        ICS: 013600 A    ICR: 014960 A
                                              INS: 0048.0 A    INR: 0384.0 A
        VAN: 010.2 KV
        VBN: 010.2 KV                               VAN: 693.0 V
        VCN: 010.0 KV                               VBN: 693.0 V
                                                    VCN: 679.4 V
        FREQ: 60.00                                 VN  : 047.0 V

        WATTS: +1888.5  KWATT
        VARS: +3777.0  KVAR

05:10:37.834  87G PHASE A ON
05:10:37.834  87G PHASE B ON
05:10:37.836  87G PHASE C ON
05:10:37.836  94G  TRIP SIGNAL ON
05:10:37.841  TRIP CIRCUIT ENERGIZED
05:10:37.898  GENERATOR OFF-LINE
05:10:41.559  87G PHASE B OFF
05:10:41.560  87G PHASE A OFF
05:10:41.562  87G PHASE C OFF
05:10:41.570  94G  TRIP SIGNAL RESET
```

Figure 2 Typical fault report generated by a digital protection system

A set of oscillography data is stored in memory each time the digital system stores a fault report. Capability to capture and store a total of 120 cycles of waveform data and 90 digital status flags is included in the digital system. The 120 cycle memory is divided in 1, 2, or 3 partitions which is user selectable. The number of pre-fault cycles captured per fault can be set up to 20 cycles. The oscillography storage is automatically triggered when a trip event occurs or it also can be triggered by an external contact input. Figures 3 and 4 present examples of waveform data and digital flags captured during a loss of excitation event.

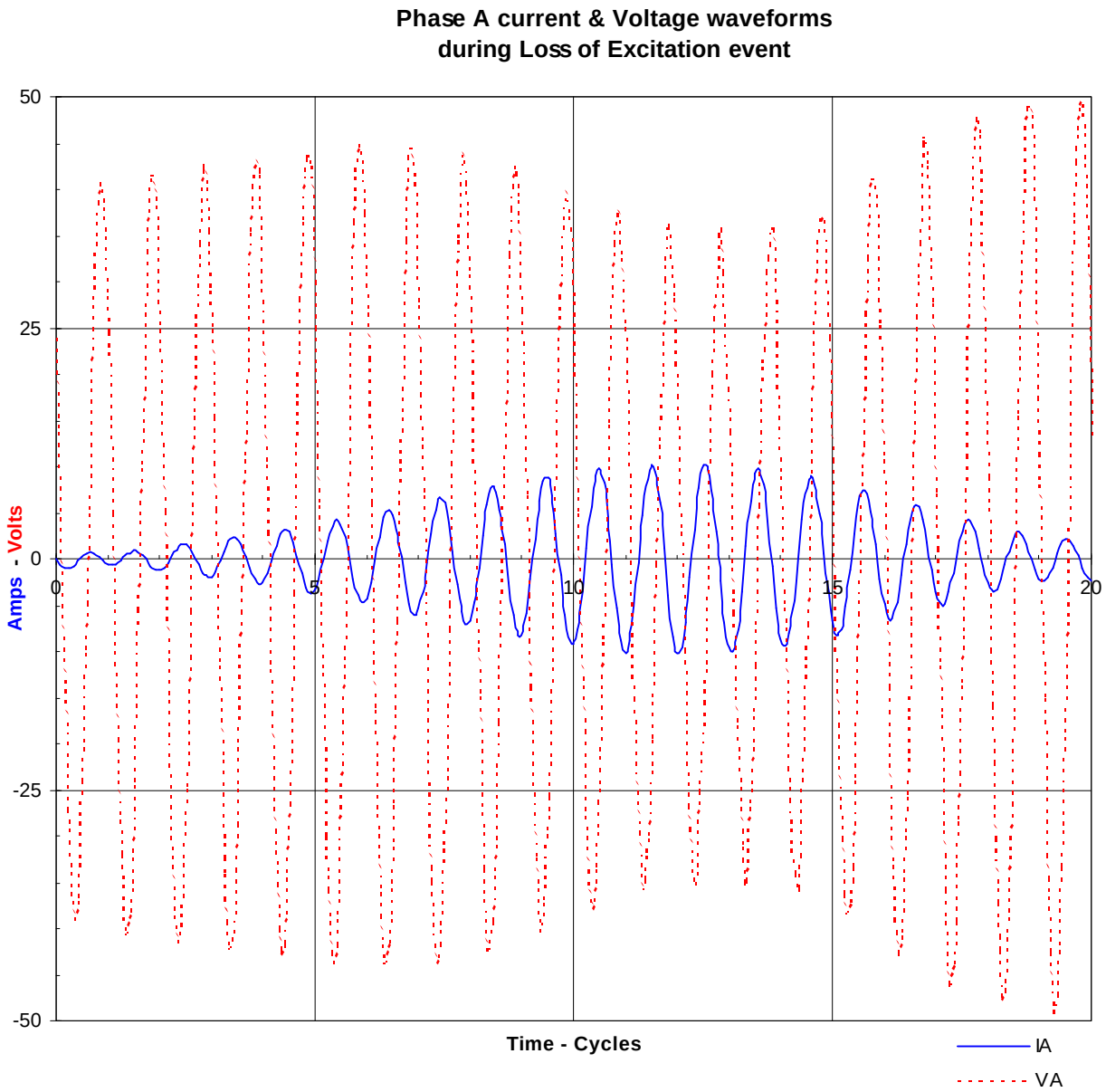

Figure 3 Typical waveforms captured by a digital protection system.
(File: test_lof.xls)

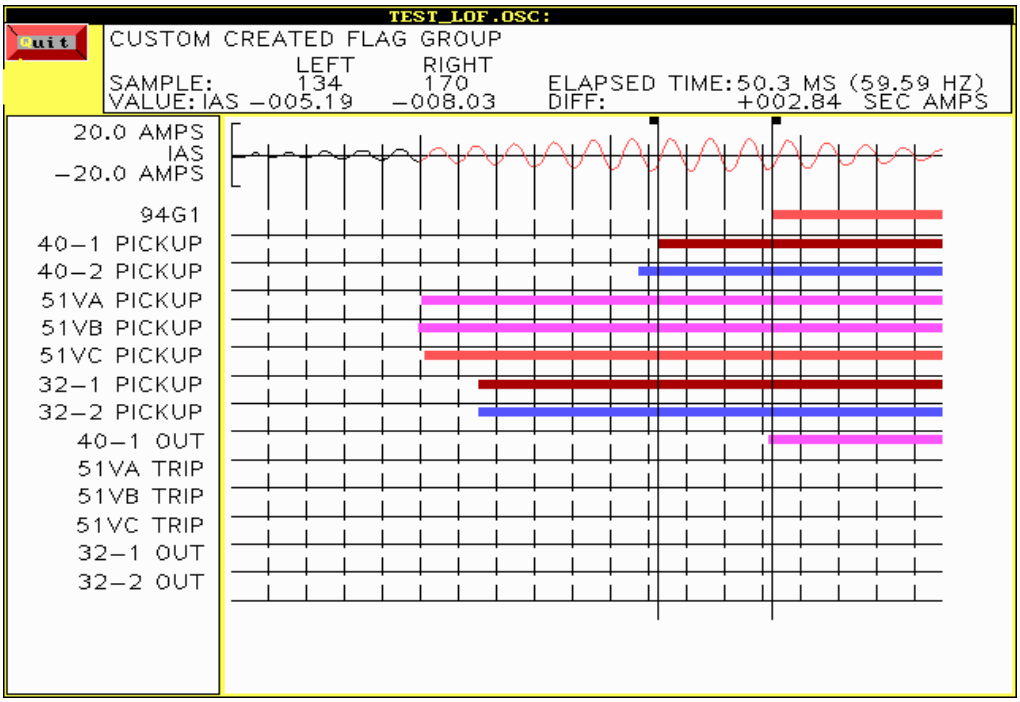

Figure 4 Typical Digital Flags captured by a digital protection system.
(File: test_lof.bmp)

Present Values Monitoring

The digital system provides metering display for analog parameters including phase currents, negative sequence current, phase voltages, % third harmonic in phase and neutral voltages, megawatts, megavars and system frequency. These displayed values can be scrolled or locked to any of the above mentioned parameters and are updated periodically.

Communications

Both local and remote communications are available with the digital system. A local man machine interface is located at the front of the system making use of a keypad, light-emitting-diode display, and 19 target LED's. A local printer connection is available at the rear of the digital system case. Remote communication is possible via two RS232 serial ports.

All of the above features will enhance the users ability to perform maintenance and fault analysis. These improvements will result in a reduction in cost associated with operation and maintenance of the facility. Using the information from the fault reports and oscillography data will help expedite trouble shooting and analysis of events and reduce outage time.

D. COST SAVINGS BASED ON IMPROVED PRODUCTIVITY AND REDUCED UNIT OUTAGES

For purposes of discussion the value of outage time is conservatively estimated at $10.00 per MW-hour. This cost is typically associated with energy production at coal fired power plants. It is clearly recognized that depending upon the circumstances this cost can be significantly higher based on demand charges and lost opportunity charges.

If with the functions and features of the digital generator protection system a one day reduction in outage time of a 400 MW unit resulted, the retrofit would be paid for in that one day reduction.

(10.00 $/ MW-hour) x (400 MW) x (24 hours) = $96,000.00

The total installed cost of the retrofit to a digital protection system is estimated at $50,000.00.

E. ADDITIONAL COSIDERATIONS

Following items are worthy of mention in reference to the retrofit:

1. Typically less than 25% of the panel space is required as compared to existing protection.
2. One unit compared to several single function components makes the installation of the digital system relatively easy.
3. Programmable control outputs provide a "transparent interface" to existing control circuits.
4. Built in test facilities can be used for current and voltage injection testing.
5. Selectable functional outputs configured to contacts can provide ease of testing and protection philosophy changes.
6. Critical failure in a digital system can degrade protection more significantly than a failure in electromechanical system. Adequate backup protection should be provided accordingly. This can be done by using selected component relays, two digital systems, etceteras.

IV. CONCLUSION

Digital protection systems are worth consideration based on the above mentioned justification to help meet the objectives of the Condition Assessment Program. This especially applies to larger units where forced outage time is extremely costly to its owners. Additionally, with many older units' protection systems approaching their end of life due to insulation degradation the present is an appropriate time to consider an upgrade to a digital generator protection system.

V. REFERENCES

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VI. Biographies

N. H. “Joe” Chau received his BSEE, MSEE in Electrical Power System Engineering from Georgia Institute of Technology, in 1973 and 1983, respectively. From 1973-1983, he was employed by Simons Eastern Company, Atlanta, Georgia, where he specialized in the paper industry. From 1983-1986 he was the electrical engineering lead for co-generation projects at the General Electric Company in Atlanta, Georgia. He is presently a Senior Engineer at Florida Power and Light Company, Juno Beach, Florida, where he is responsible for the protection and control design of the generating facilities, the service interconnection protection and control design of non-utility generation (co-generation) and other utilities. He is a Registered Professional Engineer.

Subhash C. Patel received his BSEE and BSME degrees from the M. S. University, Baroda, India in 1965 & 1966 respectively. He worked for Brown Boveri Company in India before coming to the USA in 1967. He received the MSEE degree from the University of Missouri - Rolla in 1969 and joined Illinois Power Company in Decatur, Illinois where he was primarily responsible for power system protection. Since 1979, Mr. Patel has been with GE and has had various assignments in the field of protection and control as well as gas turbine package power plants. He is currently a senior application engineer in GE Power Management at Malvern, PA. Mr. Patel is a senior member of IEEE, member of Rotating Machinery Protection Subcommittee of PSRC and a registered professional engineer in the states of Illinois and New Hampshire.

Jonathan D. Gardell is a Senior Project Manager with the Factory Mutual Engineering Association. He received his BSEE from Worcester Polytechnic Institute in 1981 and his MSEE from The Ohio State University in 1987. Prior to joining Factory Mutual, he was a Consulting Engineer with GE's Power Systems Engineering Department and an Electrical Engineer with the American Electric Power Service Corporation. In his present position, he has responsibility for review of proper operation and application of electrical systems and equipment in utility and industrial systems covered within the Factory Mutual System. Jon is a Member of the IEEE Power Engineering Society as well as a Member of the Power System Relay Main Committee. In addition he is a member of several IEEE rotating machinery protection Working Groups. He is also active in the Electric Machinery and the Energy Development and Power Generation Committees.